POWER PLANT
FUEL COST, AIR POLLUTANT EMISSION, AND O&M COST CHARACTERISTICS

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I. OVERVIEW

In the Order for the Second Phase of the Data Collection Rulemaking[1] and the Scoping Report Describing Resumption of the Rulemaking[2], the Commission's Ad Hoc Information Committee expressed its general intent for the review of the Common Forecasting Methodology (CFM). The Committee believes sufficient data should be acquired to adequately model the electricity system, that is, to simulate the western regional energy market. As part of that effort, the Committee acknowledged a continued need for power plant physical, operational and financial characteristics such as fuel price, variable and fixed cost, and air pollutant emission data.[3]

This paper addresses the issues related to the data collection of power plant fuel cost, air pollutant emission characteristics, and variable and fixed operations and maintenance (O&M) costs and is issued to help facilitate the September 17, 1998, workshop on Generator Data Needs. The goal of the September 17, 1998, workshop is to encourage discussion of alternative sources of data such that the AHIC Committee can make an informed decision as to the most appropriate source of data balancing the cost, feasibility, practicality, equity and usefulness.

Table 1 of the Scoping Report summarizes the Committee's goals for regulatory revisions and provides a general overview of the rulemaking effort and indicates where the activities discussed in this paper fit in. The subjects of the September 2nd and 17th workshops, and this and the previous staff paper are part of the Facility Characteristics aspect of Generation Data (that is, Data category 2.b. in Table 1).

Section II identifies needed power plant fuel price data, explains the increased importance of having power-plant-specific fuel costs, and discusses fuel cost data collection issues.

Section III identifies needed air pollutant emissions data and describes, explains various uses of the data in addition to energy market modeling, and discusses emission data collection issues.

Section IV identifies power plant O&M cost data and describes the issues related to its collection. Staff's paper for the September 2 workshop indicated that power plant capital costs and the associated data needed to assess a power plant's annual debt service would also be included in this paper and discussed at the September 17 workshop.[4] However, as these variables do not directly affect the energy market simulation modeling and because the collection of such data shares many issues in common with the collection of "System Data," Staff now thinks these variables should be discussed later in the process along with "System Data."

Market simulation modeling has been a key element of the electricity system assessment processes directed by the Energy Commission. Beyond the specific regulatory uses outlined in the Warren Alquist Act, a wide range of policy issues have been assessed for a wide range of purposes by Staff throughout the Commission. The market modeling studies to date can be grouped as those

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[1] Ad Hoc Information Committee, Docket 97-DC&CR-1, July 30, 1998.
[2] Docket 97-DC&CR-1, July 28, 1998, page 21.
[3] Ibid.
[4] Power Plant Characteristics For Electric System Modeling, Joel Klein, et al., Docket 97-DC&CR-1. August 14, 1998, page 9.

done for internal uses within the Energy Commission for its own studies, those done for other government agencies, and those done for private entities. A complete explanation of these uses is contained in Staff's paper for the September 2nd workshop, Power Plant Characteristics for Electric System Modeling.[5] Much of the data discussed in this paper also contributes to electric system modeling and, therefore, serves these same purposes. Where additional purposes are served by the data discussed in this paper, those purposes are described.

II. POWER PLANT FUEL PRICE DATA

A. Introduction

Monthly fuel price forecasts for coal, residual/distillate fuel oil, natural gas and other fuels[6] are an important component of an electricity generation's operational profile. The energy market simulation model uses individual power plant cost of fuel by month for each year of the forecast period. If no forecast exists, historical monthly fuel costs for the previous three years can be used by staff to derive one. The fuel price can represent approximately 50 percent of the price for electricity and also may form the basis for making the decisions to run or not to run a particular generation facility. Forecasted fuel prices are thus fundamental in support of modeling the electricity generation network serving California for forecasting environmental impacts from power generation, electricity prices, DSM program impacts on electricity demand, fuel demand, generic generation evaluation, etc. Commission models are sensitive to price differences between the various fuel so it is necessary to account for each fuel type.

B. Sources of Projections

Commission power plant fuel price projection requirements could be developed in house, or the Commission could require the power plant owners/operators to provide them. Rather than having the electricity generators provide the fuel price forecasts, it is anticipated that the Commission will be preparing fuel price forecasts to support its electricity modeling efforts. However, to meet the modeling needs of the Commission, specific fuel data for each of the major electricity generating[7] facilities will be needed. This would include the type of fuel used, fuel price components, sources of fuel, delivery information, contractual pricing arrangements, etc.

C. What Fuel Prices Will be Needed

Two forms of burner tip price will be needed for the modeling effort. First is the total price that is associated with the consumption at each site location. This is needed to assist in determining the full economic impact of using a specific fuel type. The total price would include the commodity, transport (inter and intrastate), and applicable storage costs. This price would include both the demand (fixed) and volumetric (variable) charges. .The second form of burner tip price would be

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[5] Docket 97-DC&CR-1, August 14, 1998, pages 2-6.

[6] Other fuels would include, but not be limited to biomass, crude oil, coke, nuclear fuel, purchased water, geothermal steam, etc.

[7] All electricity generation locations with total name plate generation capacity of sufficient size, or potentially significant impact on market clearing price, to warrant individual modeling.

associated with what has been known in the past as the dispatch price, which is represented by the volumetric “variable” charges.

C.1. Total Fuel Price Components (Fixed and Variable Prices)

Fixed charges are comparable to demand charges that are levied without regard to the volume of fuel supply taken. Generally, these are monthly charges and have been made in conjunction with interstate transportation or instate transmission and distribution. Such charges could also be resource or supply based, meaning the buyer has purchased resources, made supply reservations, entered into take or pay contracts, or other like charges for supply, which must be paid regardless of the quantity of fuel taken.

Variable or volumetric charges become applicable only when volumes of supply are actually taken. This would include commodity, transport fuel costs, and other such costs. These are generally expressed as unit charges and payments are simply determined by applying them to the volume of supply.

C.2. Dispatch Price - Bid Price

The second form of burner tip price would be associated with what has been known in the past as the dispatch price, which is represented by the volumetric “variable” charges. This price was associated with determining where the next increment of generation energy would be derived. Generally this was based on the variable or volumetric price. Today, this could form the basis of preparing a bid price to the PX.

For some of the fuels, all the pricing components are now considered volumetric. In these instances, other considerations are used to determine whether an operator will burn the next increment of fuel. This could be based on say, the border or city gate price in comparison with some factor. Merchant electricity generation operators may have other options for using the fuel, such as selling it directly as a commodity or moving it to another site location.

D. Generic Fuel Price Needs

These items listed below are necessary for each fuel type used to generate electricity.

- Is there company owned fuel resources used to supply the facility? If so, what is the monthly supply from these sources? What is the methodology used to set the commodity price?

- Are there other long term (longer than one year) arrangements in place to provide fuel supply? If so, what are the pricing provisions associated with these supplies? Do these include transportation to the generation facility? To the California border?

- To what extent will the operation of the facility rely on short term (one year and less) supply? Is there a regional supply preference? What would be the basis for this, i.e., lower delivered price, own the fuel supply or have existing supply contracts, contracted capacity, available nonfirm capacity, etc.?

- What is the supply mix of owned resources, other long term supply and short term purchases? For natural gas, to what extent is this supply carried by each of the interstate pipelines serving California?

- Do the contract pricing clauses in the supply contracts include transportation or are there separate contracting arrangements? Describe these transport cost provisions.

- With regard to both supply and transport, what are the price escalation factors for each supply source? Are these provisions strictly volumetrically based, or are there fixed components that are paid periodically? If there are fixed components, what is the basis for these? Are there pricing provisions that allow seasonal fluctuations, and if so, what are they?

- Are there specific factors which affect the monthly fixed and variable commodity and transport costs? If so, what are they and describe.

- For power plants with more than one supply source, what is the mix of supply from each source? To what extent will this mix vary over time (monthly and yearly)?

- What are the cost components which are included in the total burner tip price?

- Is the cost for storage factored into the cost of the fuel, and if so how?

- What are the pricing component factors which are considered in dispatching each major power plant facility? What is the decision tree for making dispatching decisions?

In addition to responses to the above questions, the Energy Commission will need recorded monthly and annual burner tip fuel prices for each facility. This information would be used to convert our annual fuel price forecast into a monthly fuel price forecast. This information would need to be filed on a monthly (not quarterly as now required) and annual basis. For other modeling purposes the Energy Commission would also need fuel characteristics which would include Btu, sulfur and ash content.

E. Individual Price Forecasts for Natural Gas Fired Power Plants

It is logical that individual fuel price information would be necessary for uniquely fueled power plants. Mine mouth coal fired power plants would qualify as each facility would be operating under different contractual fuel supply arrangements. Biomass facilities would also be considered unique in that each facility could be using a different fuel type from differing sources and under individual fueling arrangements. While Staff has not considered California's natural gas fired power plant facilities individually in the past, as described below this concept is about to change.

E.1. Changing Role of Power Plant Specific Fuel Prices

Power plant fuel consumption in California will continue to be dominated by the use of natural gas. For these power plants, there is a potential that the Energy Commission would have to prepare an individual fuel price forecast for each major electricity generation facility. This would be a departure from past methodology where the Commission prepared a system average natural gas price for electricity generation. This price forecast was uniformly applied to all generation facilities in the natural gas service area. With utility power plant divestiture and the competitive bid process in the Power Exchange, specific power plant fuel costs may be the decisive factor in determining which power plants operate.

A review of historical data indicates that each facility does have a unique fuel price. During the past five years there were differences in plant site specific natural gas prices within the same gas utility service area. Except for the Coolwater and proposed Blythe facility, it was felt that the differences were not significant to warrant separate price forecasts.

With divestiture, the price differentials between plants could become more pronounced. In the future these operators will develop strategies to maintain the lowest natural gas prices possible. This will be accomplished by utilizing the combination of the interstate sources and instate transport. Indeed, significant[8] differences between individual power plant fuel costs and a system-wide price forecast would need to be accounted for in the Commission's electricity modeling efforts. This would require the Commission to prepare a separate fuel price forecast for each of the facilities.

E.2. Determining if Natural Gas Prices will be Different

Staff believes that it is likely there will be significant fuel price differences. We believe this on the basis of the broad variation in ownership characteristics among the divested utility facilities and qualified facilities. Actual fuel data from power plant owners is needed to confirm or reject this belief. We plan to perform an assessment periodically to gauge how variation exists. We believe this is important for both projecting electric system behavior and for evaluating/diagnosing PX and competitive generation market performance.

First, will natural gas prices be significantly different between power plants in a gas utility service area? Second, can we determine if there is a significant difference? Finally, if there is, what are the different ways in which information may be gleaned from the electricity generators to make such individual natural gas price forecast possible.

The first area to consider would be to decide what is a significant natural gas price differential between a system average and individual power plant natural gas price. To some extent this may depend on the purpose of the modeling effort.

[8] What is "significant" would need to be determined.

- What would the range in price spread need to be to cause what would be called a significant change in modeling results?

- Would the significant model change in results be more or less prominent if the modeling effort was to determine environmental impacts, or generic generation penetration, or impacts of DSM, or change in demand, or electricity prices, or fuel consumption, or etc.?

- Finally, what would sort of magnitude are we talking about? 10 cents per mmbtu, 25 cents, 50 cent or more?

If there are anticipated to be no significant differences between the natural gas prices in power plants within a gas utility service area, then Staff may continue forecasting electricity generation prices as it has in the past. Staff would continue to need monthly price data by facility to determine weighted average monthly historical prices. These are used to develop factors to allocate or annual price forecast into a monthly forecast.

F. Alternative Forecasting Methods if Substantial Fuel Price Variation Exists

If there are significant differences, several approaches seem to be available. The first of these would be that the supply mix from each supply source (PG&E - NW Transport, Kern River, Mojave, El Paso or Transwestern and California production) delivered to each facility would be provided on a monthly basis, along with the weighted total or delivered to plant natural gas price. The Commission could then assume that this mix would continue on into the future which would be applied to the Commission's border supply and price forecasts. In state transport costs would then be applied to determine a forecasted facility burner tip price. The historical monthly and annual prices would be used to develop monthly factors to convert our annual price forecast to a monthly one.

A second option would be to receive from each generator, its three to five year forecasted supply portfolio. Using the Commission's border price forecasts, a weighted average price could be then be determined for each facility. In state transport costs would then be added to obtain a total burner tip price. Actually monthly burner tip prices would be needed. These would be weighted with other power plants in the service area to obtain system average monthly and annual burner tip prices. As mentioned above, these then would be used to develop monthly factors to convert our annual price forecast into a monthly forecast.

In each case, adjustments to the supply mix would be made by the Energy Commission to take into account operator owned supply and supply and transport contracts.

G. Qualification of Power Plant Fuel Prices for Confidential Treatment

Since this information is intrinsic to successful bidding in the PX and negotiations in the bilateral contract market, Staff believes fuel supply and price data qualify as a trade secret. Therefore, they would be automatically accepted for confidential protection for nonutility power plants using the

Energy Commission's recently revised confidentiality regulations. Nondisclosure would also likely to be granted under existing Commission processes for utility power plants.

III POWER PLANT AIR POLLUTANT EMISSIONS DATA

A. Introduction

Emission factors are used for a variety of purposes at the Energy Commission; electric system simulation modeling (modeling), power plant licensing (siting) and other related applications. Modeling work involves forecasting and backcasting to evaluate the effects on emissions (primarily NO_X and SO_X) of various strategies or trends in electricity demand and its supply by the generation industry. These analyses may involve a single air district or may encompass the entire western power grid. In either case, the results are greatly affected by the emission factors used. In some cases, the lack of adequate emission factors has caused delays in regulatory reviews.

Whereas modeling work typically involves a large selection of power plants, siting involves one specific power plant. During the siting process, Energy Commission staff evaluate the direct and cumulative environmental impacts of power plant construction and operation. For this purpose the emission factors used should represent the most reasonable worst case scenarios.

Other analyses include rule review for air districts or inventory development which may impact the State Implementation Plan (SIP). In some cases the emission factors drive the entire analysis, in others they only impact a small detail. Recent analyses that relied heavily on emission factors include the Greenhouse Gas Emission Inventory of the State of California, the electric vehicle study which was done for the California Air Resources Board (ARB), and a rule review involving refinery safety and hazardous material handling (not directly related to power plants).

Most of the emission factor data is not available from sources other than the power plant owners. They have, in the past, reported their emission factors to the Energy Commission as part of the Common Forecasting Methodology (CFM) filing. However, in the new deregulated market, most power plant owners are reluctant to share this information. They are asking the Energy Commission to gather the information needed from other sources. Some of this information can be obtained from the California Air Resources Board (ARB), local air districts (like Los Angeles or San Diego), the U.S. Environmental Protection Agency (Acid Rain, AP-42) or the U.S. Department of Energy, Energy Information Administration (EIA). However, none of these sources have complete information, and most have the information in forms that can not be used with information from other sources.

One possible solution is to take what information is currently available (i.e., from past CFMs and other agencies) and attempt to modify it into the form that is needed. This poses several difficult problems: First, there is the issue of confidential information from another agency. Most likely, getting that information at the level of disaggregation needed would require a legal contract or a memorandum of understanding. These have proven difficult to get in the past. Even with the disaggregated information, the task of correlating one agency's data with another is difficult. It would require knowledge of all the various agency's data collection assumptions, an explicit understanding of the Energy Commission data requirements, and a technical knowledge of power plant operations and assumptions. There are very few staff at the Energy Commission that have this combination of expertise and knowledge. This option would constitute a significant hardship on the Energy Commission.

Since all this information ultimately comes from the power plant owners, another option is to go directly to them to get the information needed in the form desired. Historically, this is what we have been doing at the Energy Commission with the Supply Forms in the CFM filings. The emission data of past CFMs have been handled by a single Energy Commission staff member, revealing the benefits to the Energy Commission of having owners of facilities organize and submit all relevant emission factors for a facility. Even if each power plant were to submit separate forms of a more detailed nature, it is unlikely that that would constitute a significant hardship on the Energy Commission staff.

Table 1
SUMMARY OF EMISSION FACTOR USES

	Modeling	Siting	Other
NO_X	For forecast modeling, NO_X emission factors are primarily required in the form of emission curves with respect to fuel consumption or power plant output. The curves can be block, exponential or polynomial in nature and must ultimately result in an emission factor in units consistent with mass-of-emissions per fuel-use, per power-output or per hour, at a prescribed level of power plant operation. However, for a baseloaded power plant, annual average emission factors have been used in units consistent with mass of emissions per fuel use or power plant output.	For siting case analyses, the NO_X emission factor must represent the most reasonable worst case operation of the power plant in units consistent with mass of emissions per hour. This may or may not include the effects of start-ups and shutdowns on the power plant's emissions. In most cases, emission factors for both pre- and post-emission control devices are required, as well as with and without devices whose operation can be easily terminated and effect the NO_X emission (i.e., inlet chillers).	The requirements for other analyses are diverse, but are most likely satisfied by either (or both) the modeling or siting emission factors for NO_X.
SO_X	In all cases in California, SO_X is calculated based on the sulfur content of the fuel being burned. It is assumed that all the sulfur, minus any sulfur reduction devices, is emitted as SO_X. The required units for modeling are annual averages of mass emissions per fuel use or power plant output. The required units for siting are the most reasonable worst case mass emissions per hour. The requirement for all other analyses are most likely satisfied by the modeling or siting emission factors.		

Table 1 (continued)
SUMMARY OF EMISSION FACTOR USES

	Modeling	Siting	Other
ROG	For modeling purposes, reactive organic gases are important due to their contribution to ozone formation. However, ROG is difficult to measure and is currently only represented by AP-42 estimates, which can not be verified.	For siting purposes, ROG emission factors represent the most reasonable worst case scenario.	Other analyses regarding ROG estimates are not reliable due to the unverifiable emission factors from AP-42.
PM10/PM2.5	PM10 emission factors are currently represented by AP-42 emission estimates and manufacturer guarantee. It is assumed that all the PM10 from power plants is actually PM2.5.	With the creation by EPA of the PM2.5 standard, both primary and secondary PM10 and PM2.5 may become significantly more important in the future.	
CO	For modeling purposes, annual average CO emission factors are acceptable.	For siting purposes, CO emission factors must represent the most reasonable worst case operational scenario for the power plant.	
Greenhouse Gases	For power plants, the carbon content of the fuel burned is used to determine the CO_2 emission factor. This information has only been used for inventory purposes, but may be used in the future to evaluate carbon emission reduction strategies.		

Table 1 (continued)
SUMMARY OF EMISSION FACTOR USES

Hazardous Materials	Hazardous material handling is a potentially significant issue associated with siting power plants. The most common concern at California power plants is the use and storage of ammonia for use in controlling NO_X emissions. The improper handling of this material poses a direct threat to public health and safety.
Hazardous Air Pollutants	Hazardous air pollutants are becoming more important in the siting process for power plants, because they are being used as an indication of environmental justice. EJ issues revolve around a group of people being forced to accept an unfair portion of the burden of additional pollutants, while the benefits of this industry are shared by all.

B. WHAT SOURCES EXIST FOR THIS EMISSION INFORMATION

B.1. Oxides of Nitrogen (NO_X)

NO_X emission curves.

The best source for this information is from those power plants that have continuous emission monitoring (CEM). From this data the power plant owners can develop block emissions, polynomial or exponential curves.

One other possible source may be the EPA Acid Rain data base. However, that information is not comprehensive and might not provide all the necessary data needed to develop the emission curves. Also, the data in the acid rain data base comes from power plants with CEM.

Annual average emission factors.

This data has several sources, including AP-42. However, the best source (excluding CEM data) is the annual source tests that are typically done at power plants to satisfy local air district regulations. The next best source for this information is the initial source test, which is required under state law whenever there is a major equipment change, as well as at the initial installation of the facility.

B.2 Oxides of Sulfur (SO_X)

Most SO_X emission factors are annual averages (for modeling) or the most reasonable worst case emission factor (for siting). In both cases, the emission factor is typically based on the sulfur content of the fuel burned. In most cases, it is assumed that 100% of the sulfur is emitted as SO_X. However, in some cases source testing has shown a SO_X emission that was lower than the fuel-based estimate. For some types of power plants, those with an expected high sulfur emission, CEMs for SO_X are available. However, natural gas fired devices emit too little sulfur for these devises to effectively measure SO_X emissions. The best sources for SO_X emission factor data is in the following order: the sulfur content of the fuel burned, CEM data, annual source tests, initial source tests.

The primary source of all this data is the power plant. The EPA Acid Rain data base does report SO_X emissions (on an hourly basis) for many power plants, but does not include all power plants in California.

B.3 Reactive Organic Gases (ROG)

There are no good sources (including AP-42) for this information for modeling purposes. When used in a siting case, the only reliable source is the manufacturer’s estimate. The only way to improve this situation is to perform source testing and speciation on power plants throughout California, a very expensive proposition.

ROG is not a criteria pollutant, so there is no SIP-related ambient air target for it. It is, however, an ozone precursor, so there is a motivation to reduce emissions or at least inventory them. There is evidence to suggest that ROG emissions from natural gas fired power plants are very low on the reactivity scale, indicating that they are a very small portion of the ROG inventory. ROG emissions from power plants are the basis for the electric vehicle equivalent study performed by the Energy Commission for the Air Resources Board. Given all this, it does seem rational to perform the necessary source tests and speciation tests to determine the ROG emission factors for power plants. The real question is how to do it in a fair manner and who will fund and control the study.

B.4. Particulate Matter less than 10/2.5 microns (PM10/PM2.5)

Like ROG, PM10 and PM2.5 are represented by AP-42 emission factors. Also like ROG, to improve this situation would require an extensive research effort.

B.5. Greenhouse Gases

Because greenhouse gas emissions from power plants are based on the carbon content of the fuel, and we know what fuel is being burned from other sources, we have all the information we will need to compute carbon emission factors and mass emissions. No further information should be necessary.

B.6. Hazardous Materials

All of the information that would be relevant to hazardous materials at power plants will be available in the EPA RMP program. No further information should be necessary.

B.7 Hazardous Air Pollutants (HAPs)

All of the information that would be relevant to hazardous air pollutants at power plants is available in the air toxic emission inventory required by California Health and Safety Code, section 44344. No further information should be necessary.

C. Additional Considerations

Different power plant technologies will report different emission factors. The following table indicates what power plant technology will report what emission factors.

Table 2
Necessary Emission Factors by Technology

Emission	Fossil Fuel	Geothermal	Renewable - Combustion	Renewable - Non Combustion	Fossil Fuel burns at Hydroelectric	Cooling Towers at Nuclear
NO_X	x		x		x	
SO_X	x		x		x	
CO	x	x	x		x	
ROG	x	x	x		x	
PM10	x	x	x		x	x
PM2.5	x	x	x		x	x
H_2S		x	x			
HAPs	x	x	x		x	
CO_2	x	x	x		x	

Some power plants have been gathering and maintaining historical data, and are prepared to submit information to the Energy Commission. Other power plants have never gathered these data, let alone submitted them. Special consideration must be given to those power plants that do not have CEMs, do not perform annual source tests and do not currently have emission controls. While this does not excuse these power plants from participating in this effort, it does mean that the Energy Commission will have to consider the ability of the power plant to report and to develop a realistic implementation schedule if reporting is to be required.

Operational differences between power plants should be considered when determining the necessary level of accuracy and precision for reporting emission factors. Power plants that are base loaded, or that are required to operate at one specific level might be able to justify using an annual average emission factor for modeling purposes. While a power plant that is load following or peaking only, to be accurate, would be required to develop NO_X emission curves and more precise emission factors in general.

D. Issue Identification And Recommendations

D.1 Oxides of Nitrogen (NO_X)

Units Required by the Energy Commission

Modeling: Emission curve equations resulting in units of mass-of-emissions pre unit-energy output, input or time. These same units for annual average emission factors.

Siting: Emission factors represent the most reasonable worst case scenario, in units of mass-of-emissions per unit-time.

Issues	Recommendations
Power plants guaranteed to be base loaded vs. all other power plants.	Base loaded power plants can use annual average emission factors as a reasonable representation of their actual emissions. Non-base loaded power plants do not have this luxury. They must use NO_X curves to represent their emissions because of their tendency to operate at different load levels.
Regularly required updates.	Annual emission factors should be updated when major equipment changes occur, operational changes occur, or every 4-5 years. This could be done in conjunction with the toxic inventory report. NO_X curves should be updated every year because that level of accuracy in emission factors is much more susceptible to power plant deterioration.

Source of data.	For NO_X curves there is only one source, the power plant. For annual averages, it is conceivable that this data could be obtained from air districts for some power plants.

D.2. Oxides of Sulfur (SO_X)

Units Required by the Energy Commission

Modeling: Annual average emission factors in units of mass-of-emissions pre unit-energy output, input or time, based on the sulfur content of the fuel burned.

Siting: Emission factors represent the most reasonable worst case scenario and the sulfur content of the fuel burned, in units of mass-of-emissions per unit-time.

Issues	Recommendations
Natural gas fire fossil fuel power plants vs. non-natural gas fired power plants.	Power plants firing natural gas emit very little SO_X, so an emission factor based on the sulfur content of the fuel is appropriate. However, for power plants that burn fossil fuels other than natural gas, a fuel-based emission factor may not be the best choice. In those cases, the CEM data, annual source test or initial source test should be used in conjunction with the fuel-based emission factor.
Source of data.	In general, the power plants are the only source of this data.

D.3. ALL OTHERS

Units Required by the Energy Commission

Modeling: Annual average emission factors in units of mass-of-emissions pre unit-energy output, input or time.

Siting: Emission factors represent the most reasonable worst case, in units of mass-of-emissions per unit-time.

Issues	Recommendations
Source of ROG emission factors.	For present information purposes, staff suggests the AP-42 emission factors continue to be used. In addition it may be advantageous for the Energy Commission

	to support research to develop more accurate ROG emission factors.
Source of PM10 and PM2.5 emission factors.	The PM10 and PM2.5 emission factors provided in AP-42 are sufficient at this time.
Source of Carbon Monoxide (CO) emission factors	Since most CEM or source tests include a CO measurement as well as NO_X, power plant owners should be able to easily provide this information.
Source of greenhouse gas emission inventory data.	The Energy Commission staff currently gets most of the necessary data for this inventory from EIA and the assumptions made by EPA. However, there is no guarantee that EIA will continue to collect this information. So staff recommends that the power plant owners provide annual fuel use totals as part of the CFM submittal.
Source of hazardous material handling.	The EPA RMP project will make available all necessary information for this data category. Staff recommends that no further submittal be made regarding this data, for those projects that submit to the EPA RMP project.
Source of hazardous air pollutants.	The California Health and Safety code currently requires all power plants to do toxic inventories every 4 years. As long as this information can be obtained from the air district or ARB, then staff recommends that no further data be submitted from the power plants.

IV. POWER PLANT OPERATIONS AND MAINTENANCE (O&M) COST DATA

A. Power plant Operations and Maintenance Data

This section identifies power plant O&M cost data and describes the issues related to its collection. Staff's paper for the September 2 workshop indicated that power plant capital costs and the associated data needed to assess a power plant's annual debt service would also be included in this paper and discussed at the September 17 workshop.[9] However, as these variables do not directly affect the energy market simulation modeling and because the collection of such data shares many issues in common with the collection of "System Data," Staff now thinks these variables should be discussed later in the process along with "System Data."

A.1. What Power Plant O&M Data Are Needed

The following operations and maintenance costs are needed for energy market simulation modeling:

- Variable O&M ($/MWh) - Expected non-fuel variable operating costs for each generating unit.
- Fixed O&M ($/kW) - Expected non-variable operating costs that occur whether the unit is dispatched or not, for each unit.

These data are needed both for in-state and out-of-state units, but the sources of data themselves are sometimes different in this regard. These data are not needed on a unit by unit basis for smaller generating units that are not modeled separately.

A.2. How Power Plant O&M Cost Data is Currently Collected

Within the previous Common Forecasting Methodology (CFM) data collection process, the California utilities provided every two years individual unit fixed and variable O&M cost data for the units they owned on CFM Form R-3A. The general cutoff in size of plant for reporting will be established as part of the final specification of the forthcoming regulations.

A.3. Frequency Of Updates And Accuracy Of O&M Data

These are two interrelated concerns. One, how often does the necessary data have to be updated to meet the Energy Commission's needs? And second, how accurate does the data need to be? Staff recommends that plant O&M data be updated biennially, as was done in the CFM process. Although staff would prefer yearly updates because some of the products which rely on the data will be produced more frequently than biennially, we understand the increased costs of compliance this would entail. We believe that biennial data collection is a reasonable compromise. While

[9] Power Plant Characteristics For Electric System Modeling, Joel Klein, et al., Docket 97-DC&CR-1. August 14, 1998, page 9.

changes may occur more rapidly in the competitive market, Staff feels that a two-year cycle for submitting data would appear less burdensome to the power plant owners. More frequent updates increase accuracy but also take time away from the time allowed for Staff to use the data for various issues analyses. Staff expects power plant operators to know their O&M costs for their own purposes and that the initial filing would be a matter of transcribing data. It is not the intent of Staff to create additional burden for the power plant owner but rather to have access to data that is already available.

A.4. Confidentiality Concerns

Existing confidentiality regulations permit respondents to request the Energy Commission hold confidential requested information that contains trade secrets or where otherwise disclosure would cause a loss of competitive advantage. Also, existing confidentiality regulations categorically prohibit disclosure of information provided by either non-utilities or utilities that could be used "to determine the fuel use or electricity generation of an individual non-utility generator.

Existing and proposed confidentiality regulations can affect the Energy Commission's access to and use of power plant characteristic data collected by other entities (e.g. the Energy Information Administration of the U.S. Department of Energy.)[10] When different confidentiality regulations conflict in their treatment of specific data, such conflicts can be overcome by a variety of means--acquiring the data directly from respondents, or acquiring respondents' individual permission to use data submitted to another entity who is required to keep the information confidential, or developing mechanisms for entities who collect confidential data to share it with other entities with a "need to know" but to guarantee its continued confidentiality.

A goal of workshop participants will be to collectively identify the specific generation characteristics for which respondents will:

1. likely apply for confidential treatment under existing regulations (and to identify the specific rationale for that application).
2. likely assert are included in the categorical protection afforded to non-utility data.
3. likely propose in the OIR new categorical protections be included in revisions to confidentiality regulations.
4. experience conflicts between confidentiality protections granted by various regulations.

Individual generator respondents may claim (1) that their heat rates, plans for capacity modifications, and other information qualify as trade secrets, that disclosure of such information would cause a loss of competitive advantage, or (2) that non-utility generator information qualify for the categorical confidentiality protection afforded information that could be used "to determine the fuel use or electricity generation of an individual non-utility generator." Secondary sources of this generator information (e.g., scheduling coordinators, CalISO, CalPX, manufacturers, EIA) may claim that their confidentiality agreements with generators prohibit their sharing of confidential information without the generator's express permission, regardless of the confidentiality

[10] Attachment D includes a list of electric power survey data it collects which EIA proposes be treated confidentially and a list it proposes not be treated confidentially.

guarantees offered. The Energy Commission may have to extend its effective confidentiality guarantees to any data received from secondary sources, and to do so in such a way as to indemnify the secondary source from penalties of inadvertent disclosure.

Nondisclosure Alternatives -- Nondisclosure of confidential data can be maintained in a variety of ways. The information may be used in analyses but not revealed in any form, aggregated with other data to protect individual respondent confidentiality, or used to develop generic assumptions for use in analysis. Currently, all three methods are employed in the use of confidential information. For example, modeling assumptions about generating characteristics for all large and small non-utility generation are aggregated to maintain the confidentiality of non-utility supplier's individual generating unit operating characteristics within the publicly-available data sets.

B. Alternative Sources Of Power Plant O&M Cost Data

Staff recognizes, along with the other interested parties, that it is necessary to use existing data sources where practicable to avoid unnecessarily burdening the power plant owners with multiple requests for the same information. Staff has sought out alternative sources of this data and welcomes references from interested parties for other reliable sources of data.

At the same time, Staff recognizes that with ongoing creation of competitive markets, more and more power plant owners will be imposing confidentiality and some of these sources of data will "dry up" and therefore can not be depended upon for the long run.

Energy Commission Staff has identified four sources of O&M cost data that are relevant to the present discussion:

1. Power Plant Owner
2. Energy Information Agency (EIA)
3. Federal Energy Regulatory Commission (FERC)
4. California Power Exchange (PX) and Independent System Operator (ISO)

B.1. Power Plant Owners

Power plant owners -- or their designated representative -- have O&M cost data as a matter of necessity in that it is needed initially for the feasibility studies and subsequently in the continued operation of the power plant. Trade associations may be able to play a role in developing uniform complete data for generators. A specialist in database development may be more efficient in the integration of various data items than individual power plant operating staff.

B.2. Energy Information Administration (EIA)

The EIA is an independent branch of the U. S. Department of Energy that is responsible for gathering, analyzing and disseminating energy-related information. EIA information for private and public utilities is available through various publications and its web site.[11]

Annual O&M costs are collected by station on Form EIA-412 from public utilities, but variable and fixed costs are not differentiated. Staff has reviewed the EIA information available on the internet and has met with EIA representatives. Staff has concluded that with a few exceptions described below, the data presently collected by the EIA is not directly useful in the modeling of power plants. The data collected by the EIA is largely historical data, which can prove useful in benchmarking a model -- that is, trying to replicate a known year for the purpose of validating a model. But, the power plant characteristics necessary for forward-looking modeling are not directly collected by EIA.

B.3. Federal Energy Regulatory Commission (FERC)

Investor-owned utilities annually submit plant operating and maintenance annual expenses via FERC Form 1, but this data is not differentiated by individual station or by variable and fixed cost components.

B.5. California PX and ISO

The Power Exchange (PX) and Independent System Operator (ISO) must necessarily have power plant characteristic data to do their jobs. Both of these entities have market surveillance and compliance units that require this data at the finest level of detail. The PX has recently posted its preliminary data requirements in this regard and these data needs appear to be virtually the same as the Energy Commission's needs in regard to power plant characteristics. Unit-specific variable and fixed operations and maintenance costs are requested from plant owners. They have also noted their intention to keep all of this data confidential without exception.

It is not surprising that this list of data is the same since as Staff has given the ISO copies of CFM filings and Elfin input data sets. We expect that both the ISO and the PX have reviewed these CFM fillings in their own delineation of the data necessary for market monitoring activities. Our speculation is that the PX is going to need to be able to model the market, and most likely will end up using a chronological transmission-oriented production-cost model similar to the UPLAN.

Staff has approached the ISO in regard to obtaining the power plant O&M cost data from them in the future. Their response was that they would not release any data without permission from the individual power plant owners.

[11] Mail address is National Energy Information Center (NEIC); Energy Information Administration, EI-30; Forrestal Building, Room 1F-048; Washington, DC 20585. Its E-MAIL address is ***infoctr@eia.doe.gov***. Its web site address is ***http://www.eia.doe.gov***.

An Energy Commission mandate which can be satisfied by a joint filing by power plant owners to the PX, ISO and the Energy Commission would be the least burdensome and efficient alternative for the power plant owners who submit data to the ISO or PX. The filings would in all probability be electronic and the incremental cost of providing the data to the Energy Commission would be a matter of adding the Energy Commission's internet address to the distribution list.